Savings in Steam Systems (A Case Study)

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Abstract

Armstrong Service Inc. (ASI) conducted an engineered evaluation at an ammonium nitrate manufacturing facility during the fall of 1999. This plant manufactures nitric acid and high and low density ammonia nitrate. The purpose of this evaluation is to identify energy losses and system improvements in the steam and condensate systems. Steam system improvements focus on lowering the cost of steam, wherever possible, with paybacks of three years or less.

Overall, this ASI evaluation identifies six (6) steam savings proposals with an average simple payback of 2.9 years.

This evaluation also identifies one system deficiency that will lead to unnecessary expenditures if allowed to continue, but would help to increase production if the suggested improvement was implemented.

The following report details the individual findings and outlines the corrections needed. The savings generated from these improvements will more than pay for themselves in short order.

Table 1. 400 psig Steam Production Costs

Total steam cost	$1,426,325/yr.
Average steam output	40,0000 #/hr.
Steam cost less sewer and electric	$5.94/1000 lb.
Natural gas cost	$3.25/MCF
Average boiler efficiency	54.0%
Average heat cost for boilers	$5.56/10^6 BTU
Water cost	$1.10/1000 gals.
Annual chemical cost	$0.10/1000 gals.
Average treated water cost	$1.20/1000 gals.
Make-up boiler feedwater	22,800 #/hr.
Average condensate temperature	200 deg F
Average condensate cost	$0.92/1000 lbs.
Average sewage cost	$0.00/1000 gals.
Average electricity cost	$0.042 per kWh

Site Observations

Steam Generation

The plant has the ability to generate steam from a number of sources. Typically, the steam requirements for the nitric acid plant and most of the high or low density plants are met with the steam generated from the waste heat boilers in the nitric acid production process. The three waste heat boilers are rated at 600 psig, 100 psig and 40 psig. In addition, an indeck gas fired boiler rated at 80,000 #/hr and 400 psig is used to supply supplemental steam. Table 1 details related costs for steam production in the 400 psig boiler.

A Kenawee Boiler rated at 14,000 #/hr and 150 psig is used as an emergency standby boiler.

Steam Distribution

Steam is distributed throughout the nitric acid plant to the various steam users. From the nitric acid plant two separate outdoor steam mains (150 and 220 psig) run approximately 1/4 of a mile to the high and low density production plants. A branch line from the high density area supplies steam to the valley area.

Steam Utilization

In the nitric acid plant 600 psig steam is used in the ammonia burning process and the steam superheater on the extraction/reheat loop of the steam turbine. The 600 psig steam is also reduced to 220 psig through the steam-driven turbine air compressor. This steam is used in the ammonia superheater and the tailgas heater. The 220 psig steam can also be reduced to 100 psig and 25 psig through reducing stations, if needed. The 100 and 40 psig steam is mainly used for tracing in the nitric acid area.

The excess 220 psig steam from the nitric acid plant is exported to the high density area and valley areas. It can also be reduced to 150 psig and exported to the low density area. The steam requirements in the valley, low density and high density areas are greater than the steam exported from the nitric acid plant. Steam from the gas-fired indeck boiler is also reduced and supplied to these areas, as required. See Figure 1 for a steam flow diagram. The main steam users in the high density plant are the evaporator, ammonia superheater, and the ammonia vaporizer. Other users are cooler heating coils and the granulator air heating coils.

The main users in the low-density area are the ammonia vaporizer and ammonia superheater. Steam is also used in the air-heating coils for the drum dryers.

Steam System Savings Proposal #1: Repair Steam Leaks

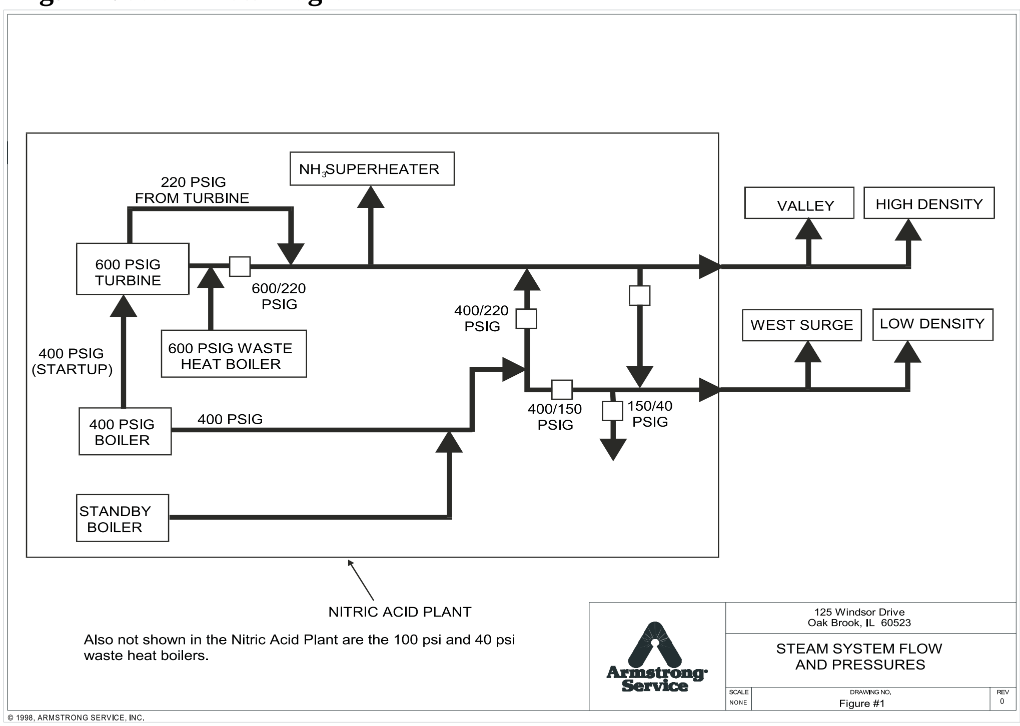
Background

In the nitric plant area a large number of steam leaks and valves were discovered open to atmosphere (see Table 2 for details). The steam leakage rate will increase during the winter months as steam tracing is turned on and more valves are opened to the atmosphere. There are also several boiler feedwater leaks and additional steam leaks in the high and low density plant areas that are not noted here.

Discussion

Unnecessary steam discharge will drive up the cost of steam. Boiler fuel usage will increase, as more fuel must be used to supply the additional steam load. The steam lost to atmosphere increases the make-up water requirements, as it is not recovered as condensate. The additional makeup water also needs more added heat and water treatment/chemicals when compared to returned condensate.

Figure 1. Steam Flow Diagram



Condensate Return

In the nitric acid plant, condensate is returned to a vented receiver/ electric pump set and pumped back to a main storage tank. A pressure-powered pump is used to return condensate from the valley area to a main return line. A vented receiver with electric pumps is used to return condensate from the high density area to the same main return line. The low density and west surge tank area also return condensate to the above main return although there are no condensate pumps in these areas. The main return line from the valley, low density, high density and west surge area returns the condensate to the main storage tank. Condensate is pumped from the main storage tank to the deaerator, as required.

Table 2. Identified Steam Leaks

Steam Leakage Rate to Atmosphere (Napiers)				
Orifice Size	Inlet Pressure	#/hr	Location	Action
0.047	400	37	Relief valve on 400 psi boiler outlet header	Repair relief valve
0.047	400	37	Control valve vent on 400 psi outlet header	Replace control valve
0.094	400	147	Flange on venting control valve	Replace gaskets, repair or replace flanges
0.094	400	147	Valve packing on bypass control valve	Repair leak/replace packing
0.047	400	37	Isolation valve on abandoned steam header	Replace valve
0.094	400	147	Valve packing on branch line to PRV station	Repair leak/replace packing
0.016	400	4	Main steam line after 400 psi boiler	Repair leak
0.063	220	37	Relief valve on 220 psi steam main	Repair relief valve
0.063	220	37	Valve packing leak on 220 main line	Repair leak/replace packing
0.063	150	26	150 psi reducing station	Repair leak
0.063	140	24	Steam supply to air tank tracing	Install steam trap
0.141	125	112	Relief valve on 100 psi boiler accumulator	Repair/replace relief valve
0.094	40	19	Tracing blow down valve	Replace valve
0.094	40	19	Tracing on 600 psi control valve	Repair leak
0.109	40	26	Tracing steam for caustic soda tank pumps	Install steam trap
0.094	40	19	Tracing steam	Repair leak
0.125	40	35	Union on drip station ahead of 40 psi PRV	Replace union
0.125	15	19	Valve cracked open on takeoff line ahead of caustic tank	Install steam trap
0.125	15	19	Valves open to atmosphere on end of branch line in water treatment area	Install steam trap
0.125	15	19	Tracing line leak near cooling tower	Repair leak
0.19	15	42	Valve packing on control valve to deaerator (inlet valve)	Repair leak/replace packing
0.06	11	4	Valve packing on control valve to deaerator (outlet valve)	Repair leak/replace packing
0.13	15	19	Tracing line leak near waste heat boiler accumulator	Repair leak
	Total #/Hour	1,033		

As can be seen in Table 2, a number of "small" leaks can add up to a large annual cost, so it is imperative that all steam leaks be repaired as quickly as possible. If the leak is ignored, the steam loss will increase over time, as will the cost of repairs.

Recommendations

Repair steam leaks as identified in Table 2, especially the high-pressure ones, and install steam traps in lieu of partially open valves.

Estimated Savings

The estimated annual cost savings for repair of steam leaks in the nitric acid plant, and installation of steam traps where needed, is $53,000/year.

Costs

The expected payback period is 1.5 years.

Steam System Savings Proposal #2: Correct Trapping on High Density Evaporator

Background

The condensate drainage method from the evaporator in the high-density area has been changed from the original design. The evaporator originally had a condensate pot with a liquid level control on its outlet to meter condensate flow. This was in essence an expensive electronic steam trap. The liquid level controller and control valve have been removed and a gate valve is now installed in place of the control valve. The gate valve is manually set to control condensate flow. The condensate from the evaporator is discharged to a pressurized flash tank (100 psig) and is then piped to an atmospheric receiver where it is pumped into the condensate return line to the nitric plant. The steam plume off the atmosphere receiver's vent is substantial. See Figure 2 (on page 52) for the current piping arrangement.

Discussion

Using a gate valve to control condensate flow from the evaporator's coil can cause a number of problems. Unlike a properly functioning steam trap (electronic or mechanical), the gate valve cannot modulate its discharge orifice size in response to condensate load variations. If the gate valve is not open enough, condensate will back up into the evaporator coil when the load increases. This means poor equipment performance and possible damage due to water hammer. The obvious solution is to make sure the valve is always open far enough to pass even the highest condensate loads. However, when the condensate load is less than the peak value, the valve will allow live steam, as well as condensate, to pass through it. While this live steam flow may not adversely affect the coil's operation, unless it is a very high amount, it does make the overall steam system very inefficient. Higher steam flow leads to increased pressure drop (loss of energy), and the potential for erosion and water hammer in the steam distribution piping is increased. Excessive steam flow to the condensate system will increase the back pressure to all other steam users that return condensate and also may lead to water hammer, as is the case here.

The evaporator drainage system was also originally designed to make use of the 100 psig flash steam generated from the 220 psig condensate. The 100 psig flash tank is still in place, but the original user (HVAC coils in the air handler in the truck loading offices) has been removed. Excessive live and flash steam from the evaporator will quickly elevate the pressure in the 100 psig flash tank to the evaporator's steam supply pressure (220 psig). To prevent this, the bypass valve around the 100 psig flash tank is open and venting this steam to the condensate line that runs from the 100 psig tank to the atmospheric tank. As a result, a very large amount of steam is being vented from the atmospheric tank and water hammer and erosion is prevalent in the system.

Recommendation

The first priority is to eliminate the excessive amount of steam being vented from the atmospheric tank by installing a properly sized steam trap in place of the gate valve that is currently being used to control flow. The bypass valve on the 100 psig flash tank also needs to be replaced as it more than likely has been damaged by steam flow through it while in the partially open position. See Figure 3 (on page 52) for the proposed piping modifications.

To further optimize the system, the 100 psig flash steam from the flash tank must be utilized. Based on the design steam load for the evaporator of 13,724 #/hr, the flash steam produced from the 220 to 100 psig reduction would be 769 #/hr. If this steam and condensate is further reduced to 0 psig, the total amount of steam being vented would be 2,312 #/hr. If the 769 #/hr of 100 psig steam is reused, the amount of vented steam at 0 psig will be reduced to 1,440 #/hr. Two possible uses for the 100 psi flash steam are steam coils for the air heater or the cooler heating coils.

Estimated Benefits

Estimating an excessive steam usage of 2 percent, due to the use of the gate valve as a steam trap, gives an annual dollar loss of $13,700/year. In addition, recovering the 100-psig flash steam for use in the air heater equates to an annual cost savings of $38,300/year. The total annual cost savings would be $56,000/year.

Costs

The expected payback is 2.8 years.

Steam System Savings Proposal #3: Improve Condensate Return from Low Density Plant

Background

There are two main steam supply lines to the high and low density and valley areas and both lines are 6" diameter pipe. There is one main condensate return line to the nitric acid plant and this line is 4" pipe. The high density and valley areas both have condensate pumps to return condensate to the main return line. However, there are no condensate pumps in the low density area other than the small pumps for the large storage tank on the hill. The combination of pumped condensate from the high density and valley areas and biphase condensate from the low density area is causing severe water hammer in the condensate return line. In addition, condensate from the large storage tank, and other steam users in the low density plant, can not be returned due to high back pressure in the return line. Currently, this condensate is drained to the ground.

Discussion

The lack of condensate pumps in the low density plant means that the condensate flow from this area is biphase. In other words, there is both flash steam and condensate in this return line. In a biphase condensate system, the condensate typically flows due to the gravity pitch of the line, and flash steam flows as a separate phase over the top of the condensate due to the steam pressure drop. This arrangement works best if there is a head pressure difference (gravity) in between the equipment and the final drainage point and the final drainage point is at zero or very little pressure. If a piping elevation rise or back pressure

Figure 2. Current High Density Evaporator Piping

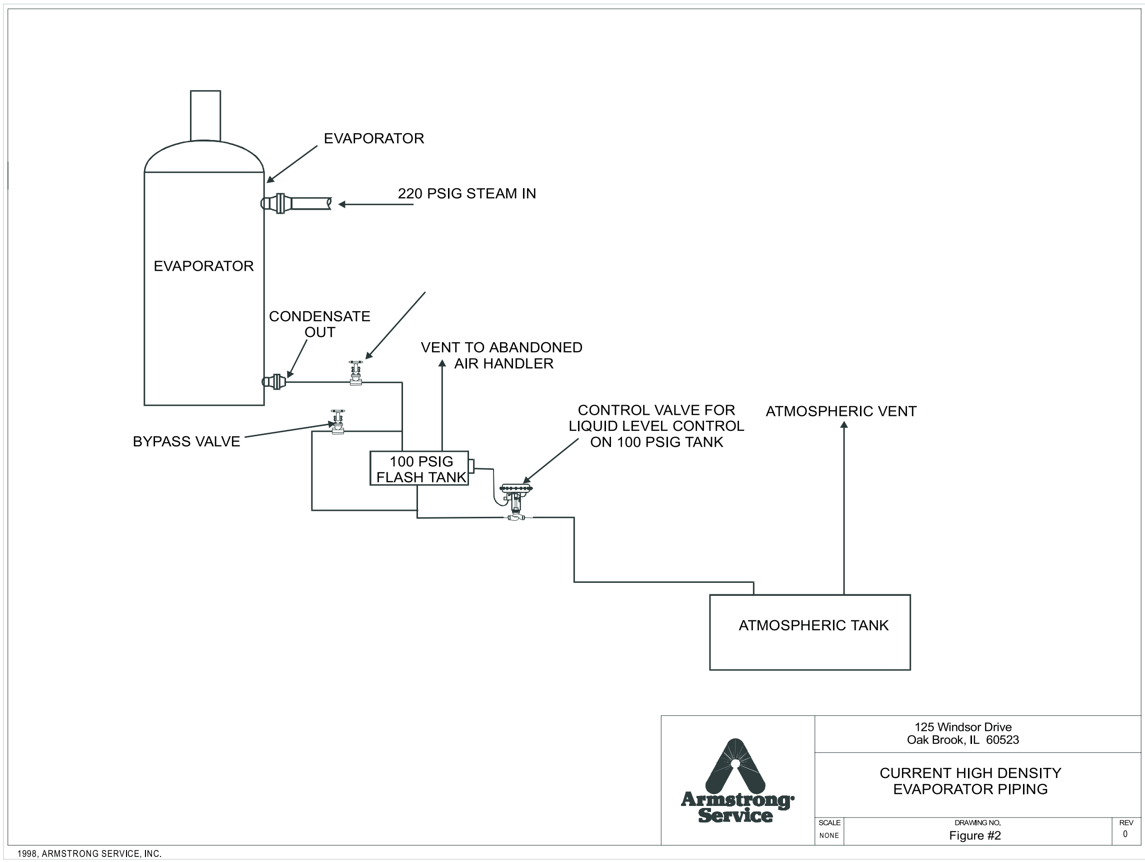
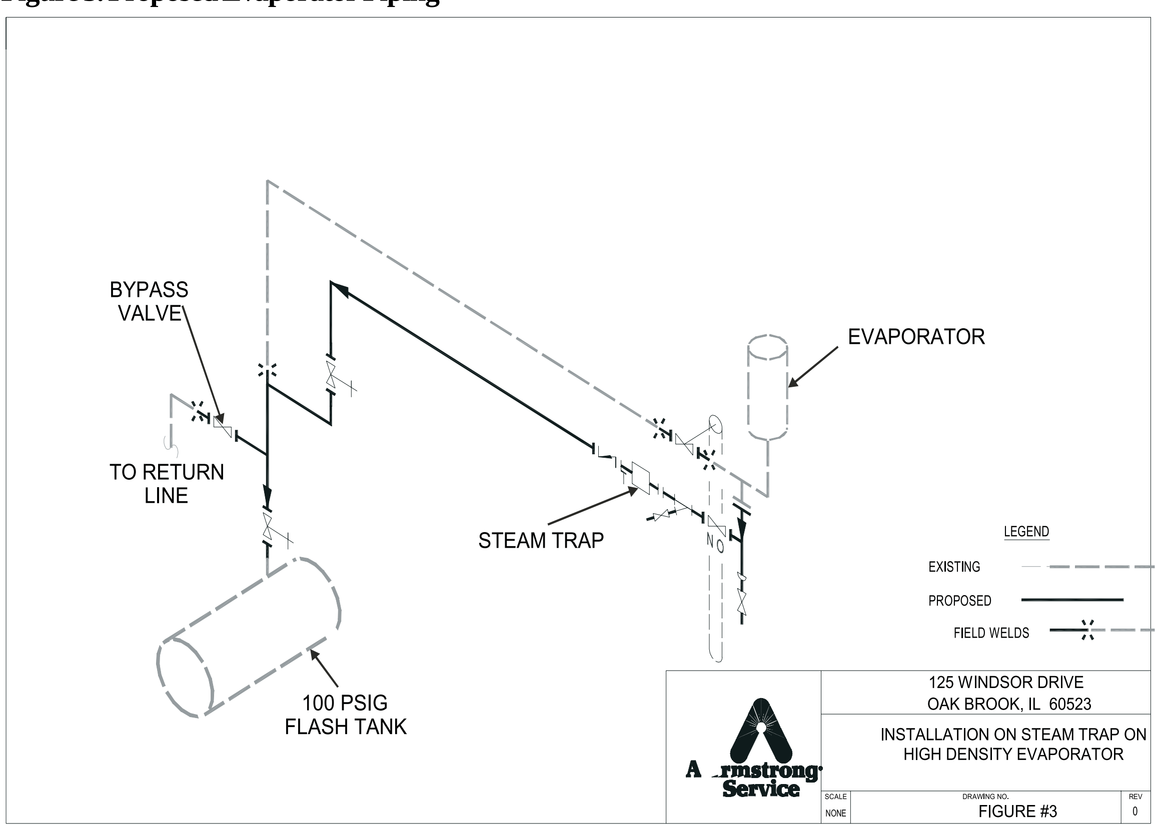


Figure 3. Proposed Evaporator Piping



exists in the line, the condensate must collect in the pipe to the point where it seals the pipe off. Then the flash steam will build until there is enough pressure to push the condensate. The resultant slugs of condensate will move very fast (up to 90 MPH) and slam into any elbows, tees or fittings. This is called “differential” water hammer. Additional water hammer will occur when the flash steam from the biphase flow is introduced into the pumped condensate line. The flash steam will instantly condense in the cooler condensate creating an implosion/explosion reaction. This is called “thermal” water hammer. In addition to the water hammer, back pressure in the return line will be present at the steam traps that are not isolated from the line by a receiver/pump combination. This back pressure will prevent proper condensate drainage on the steam-using equipment.

Recommendation

When condensate cannot flow by gravity to the final drainage point or high backpressure exists in the return line, a pump must be used to give the condensate the motive force it requires. In this case, a pump and receiver package should be placed in the low density plant to collect condensate and pump it back to the nitric acid plant.

Estimated Benefits

The estimated cost savings available by returning condensate that is currently being drained in the low density area is $17,000/year. Additional benefits will be realized in overall system operation, safety, and equipment life.

Costs

The estimated payback is 3.8 years.

Steam System Savings Proposal #4: Recover Waste Heat in Boiler Blowdown Water and Flash Steam

Background

Blowdown water from the high-pressure (600-psig) waste heat boiler in the nitric acid plant is piped to a 20 psig flash tank. This allows a small percentage (22 percent) of the hot condensate to “flash” into the low pressure (20 psig) steam line. The condensate is sent to an atmospheric flash tank where additional flash steam (4 percent) is released into the air and the remaining condensate is discharged directly to the sewer. Also, in the nitric acid plant area, condensate from the high pressure and medium pressure (220 psig) users is piped to a different 20 psig flash tank and, again, this flash steam is piped to the low pressure steam line. The condensate from this 20 psig flash tank, along with condensate from the low pressure steam users and the turbine’s surface condenser, is piped to a large atmospheric tank. The flash steam from this tank is vented to the air and the condensate is pumped back to the deaerator tank.

Discussion

Valuable heat in the high-pressure boiler blowdown water and in the flash steam from the large atmospheric tank vent is being lost to the surroundings. This heat can be recovered by using it to preheat deionized makeup water to the deaerator.

Recommendation

A deionized water supply line is already in place to the high-pressure boiler area. A stainless steel shell and tube heat exchanger, that was previously used to preheat ammonia, has been abandoned in place. This heat exchanger can be relocated and used to transfer the heat in the high-pressure boiler blowdown water to the deionized water. The preheated makeup water can then be sprayed into the vent line on the large atmospheric tank, which will condense the flash steam that is currently being vented. This will reclaim the heat and the water that would otherwise be lost to the air as steam. See Figure 4 for proposed arrangement.

Estimated Savings

The estimated cost savings for this proposal is $16,445/year.

Costs

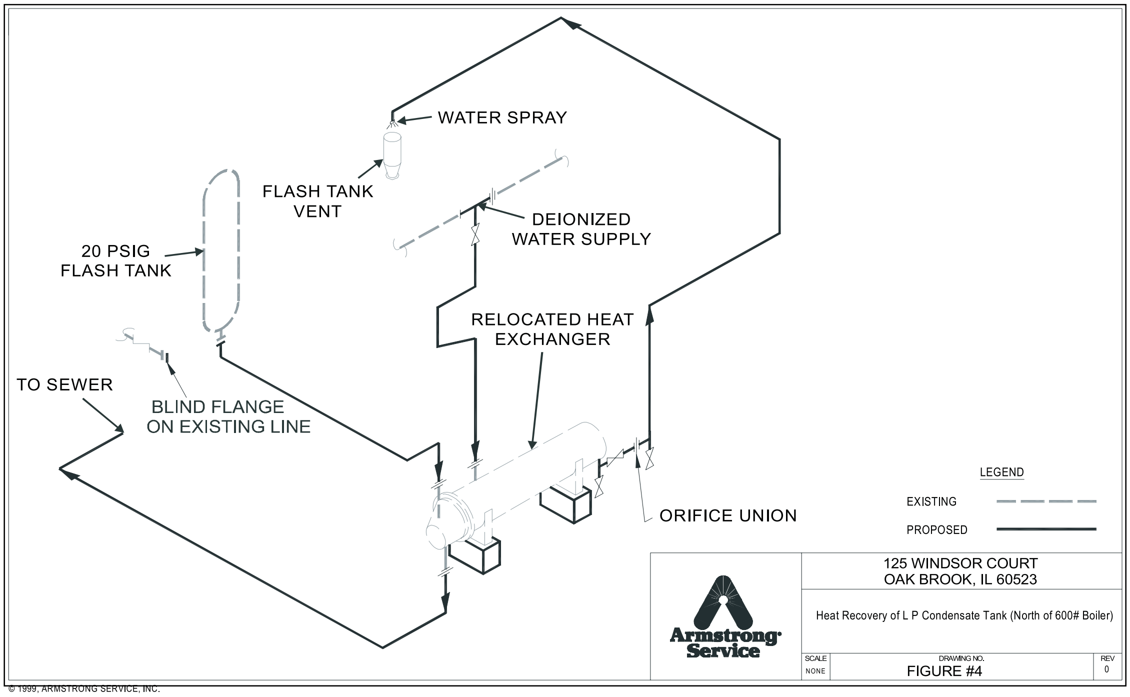
The estimated payback is 6.5 years.

Steam System Savings Proposal #5: Steam Trap Repair and Replacement

Background

There are approximately 210 steam traps at this facility. A steam trap survey was completed in January of 1999. Of the 170 tested steam traps in service, 62 had failed; this equates to a 36 percent failure rate. Based on information from the plant, it is assumed the failure rate of 36 percent has

Figure 4. Proposed Piping for Boiler Blowdown Heat Recovery



decreased, through ongoing maintenance, to 14 percent, resulting in an adjusted annual steam loss of 14 million pounds. Using a steam cost of $5.97 per thousand pounds and an operational time of 6800 hours/year, the annual dollar loss (monetary losses) is estimated at $100,000.

Discussion

The energy efficiency of a steam distribution and condensate return system is strongly dependent on the effective usage of steam traps. The basic function of a steam trap is to prevent live steam from blowing through and to allow condensate that is formed, due to heat being released in the system, to be drained. Efficient removal of condensate is necessary to avoid backup of condensate in the system. Condensate backup deteriorates the heat-transfer process efficiency, causes corrosion, and may lead to severe damage caused by water hammer in steam distribution lines, valves and equipment. The second function of a steam trap is to facilitate the removal of air from the steam distribution system. Air is present in the system during start-up, and is introduced with the makeup water and through vacuum breakers. The presence of air in the system deteriorates heat transfer efficiency by insulating the heat transfer surface and causing corrosion when it is absorbed by the condensate.

To provide long-term and energy-efficient performance of steam traps, the priority aim is to establish an adequate maintenance system. Once all the changes and recommendations have been implemented, the following preventive maintenance guidelines should be used.

In general, all steam traps should be tested at least twice each year - once in the fall and once in the middle of the winter. The recommended test method should be a combination of visual, sonic, and temperature methods. See the following table for more specific testing frequency guidelines. Keep a good record of the updated information. A steam trap computer database program is the best way to store and maintain these records. The database can also be used to store piping drawings of each trap application and prior history or problems with the traps. It should be used to print out

Table 3. Trap Testing Frequency

Operation Pressure (psig)	Application			
	Drip	Tracer	Coil	Process
0-100	1	1	2	3
101-250	2	2	2	3
251-450	2	2	3	4
451 and above	3	3	4	12

all traps by the areas that need to be tested. Each trap, as it is tested, can now be checked off. Any changes that have been made to the tag number should be "written over" the old entry on the computer printout. This becomes the input to the computer.

As each trap is tested, all strainers should be blown down for a couple of minutes to ensure they are clean. Each isolation and bypass valve should be closed and ultrasonically checked for leakage.

Every trap, valve, or strainer that has failed should be tagged for replacement or repair.

A well-run steam trap management program will:

- Reduce operating costs.
- Improve safety.
- Increase production or service.
- Reduce maintenance and other costs by eliminating condensate return problems, freeze-ups, water hammer and corrosion.

In summary, using failed steam traps or not using any, leads to three ways of waste:
- Waste of live steam through the failed trap.
- Disturbing the local condensate return system. The high back-pressure in the condensate return lines decreases the pressure differential across the other traps, thus decreasing their discharging capacity.
- Deviation from the required outlet temperatures of the heated fluid could lead to product material disturbances or more heat input.

Recommendation
It is recommended to replace all the identified defective and misapplied steam traps. Plants should also institutionalize a steam trap maintenance program by replacing steam traps with statistical projected failure during the maintenance contract period in order to supply better quality of steam and to achieve better performance of steam-using equipment.

Estimated Benefits
An estimated annual cost savings for replacing all identified defective steam traps and institutionalizing a steam trap maintenance program is $100,000.

Cost
The estimated payback period is 2.4 years.

Steam System Savings Proposal #6: Boiler Optimization

Background
During the plant-wide steam system site evaluation, ASI engineers were able to test, visually inspect and observe the operation of both the Indeck and Kewanee boilers. As a result of this evaluation process, the Indeck boiler was found to have the highest potential for significant energy savings. Therefore, this steam system savings proposal will address the improvements with the greatest impact toward increasing energy efficiency which involve upgrading and replacing controls, transmitters and loops, and boiler and burner boiler casing.

Discussion
A distributed control system (DCS) is designed to take control of the process or the plant. In the power industry, the term distributed control system (DCS) is generally applied to the system that implements boiler control and data acquisition functions of the power plant.

A state-of-the-art DCS is typically composed of modularized microprocessor-based processing units, input modules, output modules, operator workstations, engineering workstations, printers and other types of peripheral devices, all connected through a multiple-level communications network. DCS manufacturers have standard modules for different functions. They generally fall into two categories: control modules and data processing modules.

The control modules are structured to perform a variety of control and computing tasks, such as PID (proportional plus integral plus derivative) control, binary logic, and arithmetic functions. Some manufacturers have separate modules for modulating and on-off control functions and others have combined the two into one module. For some manufacturers, each module is available in varying sizes to suit a user's needs.

In addition to the control functions, the DCS needs programs to implement all operator interface, report generation, and data storage and retrieval functions. The manufacturers generally divide these functions into separate packages, each with a specially structured program that serves as a platform for the user to develop graphic displays, other forms of data presentations and format operating logs. In general, the programming functions are user-friendly and menu-driven, so that they can be a programming tool that is easily understood by the user's personnel.

Programming functions are conducted from the engineering workstation, usually with a full complement of CRT screen, keyboard, auxiliary memory, and floppy disks. The workstation is normally connected to the DCS communications network, and the programs developed from the workstation can be directly downloaded to the individual processor modules in the system.

A DCS application in a boiler house operation typically covers the following areas:

- Boiler controls, including the combustion (firing rate), furnace draft, steam temperature, and feedwater control loops.
- Burner control.
- Control loops in the plant auxiliary system that need to be monitored and/or controlled from the central control room.
- Alarm annunciation and recording features.
- Monitoring function for other separate stand-alone controllers or control systems.
- Remote indication and recording of plant operating parameters.
- Periodic reports and event logs.
- Historical data storage and retrieval functions.

In nearly all power plants and boiler house operations built in recent years, the monitoring and data processing tasks that the DCS is capable of handling have largely replaced the conventional mimic panels, annunciator light boxes, indicators, and recorders in the plant control rooms. It should also be mentioned that DCS application in plants has been expanding into motor controls for the balance of plant equipment (pumps, fans, etc.), which was once predominantly an area for PLC applications. At the present time, the choice between PLC and DCS for this application is largely a matter of cost and user's preference.

The next area to be discussed is that of burners. Burner designs continue to be developed and are capable of meeting new industrial standards without the use of flue gas recirculation for certain applications. By using a combination of an air-fuel lean premix and staged combustion, peak flame temperatures are reduced without the need for flue gas recirculation. While the staged combustion is a unique burner design, it can be effectively used in today's modern boiler applications. New boilers, as well as older operating boilers requiring retrofitting, will benefit from these successful developments.

Finally, during flue gas testing analysis, our engineers discovered higher than normal oxygen percentages. The location and the cause were confirmed during a later outage. In addition to the casing leak, two locations along the rear side walls and roof areas were found to have broken or missing refractory. The rear wall casing that houses an inspection sight glass port was also found to be deteriorated and was in need of repair.
The problems discovered with regard to broken and missing refractory and the boiler-casing leak do result in heat loss that directly effects the loss of thermal efficiency.

There are three major recommendations proposed for this steam system savings proposal.

Option 1

Recommendation

Repair casing and refractory leaks on existing boiler, tune existing burner system after refractory repair, and continue with normal operation of the existing boiler.

Benefits

The estimated cost savings available by repairing the existing boiler and tuning existing burner system is $64,000. The dollar total is based on a 4.5 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 1 estimated payback is 7.5 months.

Option 2

Recommendation

Evaluate, select and install a distributed control system for a boiler control upgrade. A distributed control system should contain the following minimum requirements:

- Highly reliable system architecture.
- Open architecture programming and communications.
- High accuracy inputs with noise and input spike protection.
- Capable of complete power supply, processor and/or I/O redundancy.
- Hot swappable I/O cards.

In addition, plants should evaluate, select and install a burner package that will guarantee a highly reliable efficient operation with excellent turndown capabilities.

Any equipment selected to meet the terms and conditions of this recommendation should be guaranteed under manufacturers' warranties.

Benefits

The estimated cost savings available by replacing the current burner controls and installing a new DCS, along with Option 1 recommendation, is $99,843. The dollar total is based on a 7 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 2 estimated payback is 3.3 years.

Option 3

Recommendation

Replace the existing boiler, burner and distributive controls system with I/O loop transmitters controls with new equipment with similar capacity as the original equipment. The boiler that is selected will have a steam capacity of 75,000 lb/hr at 350 psig/600°F superheated steam. The boiler will be equipped with a stack economizer. The burner should have a dual fuel capability (natural gas/propane with air atomization or natural gas/#2 fuel oil with steam or air atomization). With either burner that is chosen, it should be of the low excess air style to achieve highest efficiencies.

Benefits

The estimated cost savings available by replacing the existing boiler with a new boiler, new boiler controls and a new distributive control system with I/O loop transmitters is $121,238. The dollar total is based on an 8.5 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 3 estimated payback is 10.5 years.

Steam Systems Improvement Proposal #1: Steam Trapping of "Fish Pond" Pipe Coils in Low Density Area

Background

The low density plant has a pit with steam heated pipe coils referred to as the "fish pond". The condensate from these pipe coils must be lifted (siphoned) to the steam trap. The current steam trap arrangement has a bypass around the trap without a valve. This bypass appears to be wide open, which allows "live" steam to be discharged into the condensate return line. The water hammer in the piping at this location is very evident.

Discussion

Elevating condensate up a lift in a siphon drainage situation will allow some of the condensate to flash back into steam. This flash steam will lead to sporadic trap operation and ineffective condensate drainage from the coil. In this situation, a bypass has been placed around the trap to route the flash steam around the steam trap. Currently, the amount of steam that is being routed through the bypass cannot be controlled. The current piping arrangement prevents the steam trap from functioning properly and leads to excessive steam waste. The discharge of live steam into the condensate system causes the water hammer noted above.

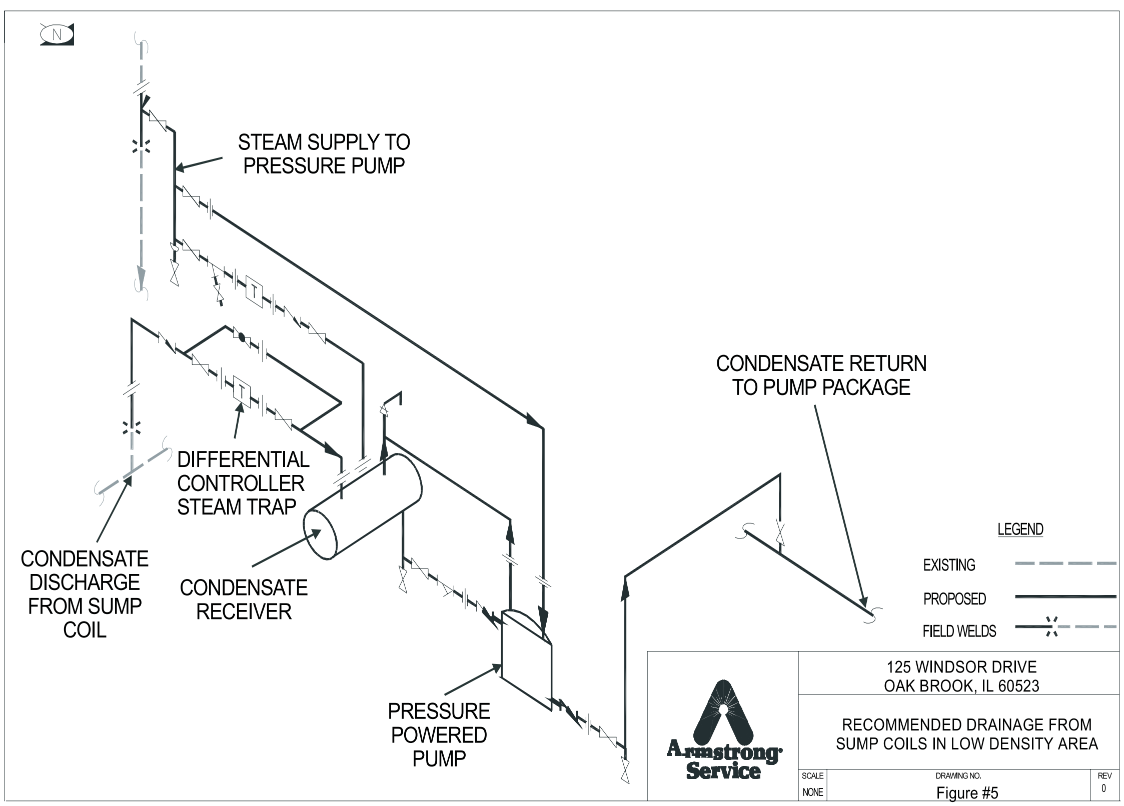
Recommendation

The condensate drainage on the pipe coils should be reconfigured to allow the use of a differential controller (DC) steam trap. The DC trap has an internal steam bleed that can be metered to control the flow rate of the bypassed steam. Condensate from the steam trap will be routed to a small receiver/pump package and then pumped back to the condensate receiver and pump package proposed in Steam Systems Savings Proposal #3. The proposed piping is shown in Figure 5.

Estimated Benefits

The main benefits to this proposal will be improved coil performance and elimination of the water hammer. There will be a decrease in the amount of steam usage, but an estimate of the amount of steam being wasted cannot be obtained with the data available.

Figure 5. Proposed Steam Trap Piping for "Fish Pond."



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